SECTION VII

Reservoir Mechanics

The reservoir mechanics of the Cockfield formation were modeled using a flow model to simulate the changes in the reservoir properties due to injection at the TexCom Gulf Disposal, LLC, WDW-315 well. Prior to modeling the fluid flow and pressure build-up in the injection zone due to wastewater disposal at the facility, developing an understanding of the regional and local geology was essential. A comprehensive picture of the subsurface geology was developed for the facility through the interpretation of borehole geophysical logs, reviews of subsurface maps, and literature sources (information detailed in Section V of the permit application). Once the range of geologic parameters was established, this information was added to the information collected during reservoir testing of the formation and reasonably conservative values were applied as input parameters for the flow model. Parameters include the following:

- Injection interval layer thickness, permeability, porosity, structure, and compressibility;
- Original formation fluid viscosity, density, and compressibility; and
- Initial formation pressure.

The results of the modeling were used to define the operating characteristics of the injection well. The model predicted pressure increases in the formation are compared to calculated values for fracture pressure, injection pressure and cone of influence values to simulate the effects of 30 years of injection at the facility. The following sections provide details on the reservoir mechanics, modeling, and proposed operating parameters for the injection well.

VII.AStratigraphy and Lithology

Through the review of electronic logs performed on the TexCom, WDW-315 well and review of literature the following stratigraphy and lithology was defined for the injection reservoir and its relationship to the injection zone and its confining unit.

The injection zone and its confining unit are defined for the application as being contained within the Jackson and Cockfield formations. The injection reservoir is being defined as the Middle and Lower Cockfield. Individual stratigraphy and lithology information is presented for the formations below.

VII.A.1 Jackson Formation

The massive marine shales of the Jackson Formation form the Upper Confining Zone of the WDW-315. Both the upper and lower contacts of the Jackson are sharp discontinuities with overlying and underlying sands. The Jackson makes an excellent Upper Confining Unit that will prevent upward migration of injectate into USDWs. This thick shale will effectively seal the 100-foot to 150-foot fault that is present approximately 7,300 feet south of the well and it will seal any smaller, unknown faults that may occur in the Tertiary sequence.

VII.A.2 Cockfield Formation

The Middle Eocene Cockfield Formation in the area of WDW-315 and Conroe Field is stratigraphically equivalent to the Yegua Formation of the deep subsurface. This formation of approximately 3000 feet of upper sand and lower shale forms a major oil reservoir in this portion of the Gulf of Mexico basin. The Cockfield Formation can be broken down into four stratigraphic units.

VII.A.3 Upper Cockfield Member

The Upper Cockfield is predominantly sand with two main shale interbeds and numerous very thin shale partings. The Upper Cockfield Member is the horizon that has historically produced oil at the Conroe Field; the included sands are of very high quality with porosities in excess of 30%. Thicker individual shales up to 42 feet in thickness separate the sand packages. There is a total of 188 feet of clean sands in the Upper Cockfield with the thickest individual sand being 29 feet thick in the WDW-315 well. Sands appear to range from 27% to 35% but average approximately 32%. Porosities are highest in the Upper Member of the Cockfield, perhaps due to the effects of hydrocarbons protecting the rock frame from diagenetic porosity plugging. The upper contact of the Member is a sharp discontinuity between the Jackson Shale and an uppermost seven-foot thick sand. The lower contact is between a particularly persistent 32-foot shale that sits on top of the deltaic sands of the Middle Cockfield unit.

VII.A.4 Middle Cockfield Member

Within the WDW #315 well, the Middle Member consists of 416 feet of largely progradational, deltaic sands separated by somewhat thick, persistent shales. The Middle unit in the vicinity of the WDW#315 well, is always below the original oil/water contact and therefore was not productive of hydrocarbons. Sands range up to 49 feet thick while porosities range up to 33% but average approximately 29%. Because no thick shales divide the Lower or Middle members, the two are connected across the 100 to 150-foot fault to the south of the well.

VII.A.5 Lower Cockfield Member

The Lower Cockfield member is present in the WDW-315 well as 345 feet of shales and thin sands. The sands appear to be thin pro-delta extensions of deltaic packages being deposited updip to the north. The sands are uniformly lower quality than those above with porosities ranging up to 29% but averaging approximately 24%. Sands are mostly thin bedded with shale interbeds; the thickest sand appears to be seven feet thick while most are much thinner. The Middle and Lower Cockfield are part of the Injection Zone of the WDW-315 well. Because no thick shales divide the Lower or Middle members, the two are connected across the 100 to 150-foot fault to the south of the well. The Lower Cockfield marine sands correlate very well between boreholes.

VII.A.6 Cockfield Shale Member

The lowest unit of the Cockfield is the Cockfield Shale Member. In the WDW-315 well, only 182 feet of this thick shale was penetrated. The unit consists of massive marine shale with few thin sands and tite siltstones; only two feet of porous sands appear to be present in the WDW-315 well. The Cockfield Shale forms the Lower Confining Unit for the WDW-315 injection system. In the North Conroe area and in the AOR, only two boreholes penetrated the entire Cockfield Shale section; these wells encountered 1,425 feet and 1,739 feet of shale.

With the massive Jackson shale and Cockfield shale, the injectate in the Cockfield sands will be confined by massive marine shales from above and below.

VII.B Injection Reservoir Parameters

VII.B.1 Injection Reservoir

The following table presents the information on the injection reservoir identified from electronic logs performed on the injection well and additional data collection performed on the subject area. The injection reservoir is contained within the injection zone identified above. The identified injection reservoir used in the modeling effort relative to the layers presented in Table VII-1 is described below.

TABLE VII-1
Injection Reservoir Layer

Formation	Layer Top Depth (ft, bls)*	Gross Layer Thickness (ft)	Net Layer Thickness (ft)	Porosity (percent)
Middle Cockfield (past fault)	5546	794	401	29
Lower Cockfield	6045	345	145	24

* At Wellbore location.

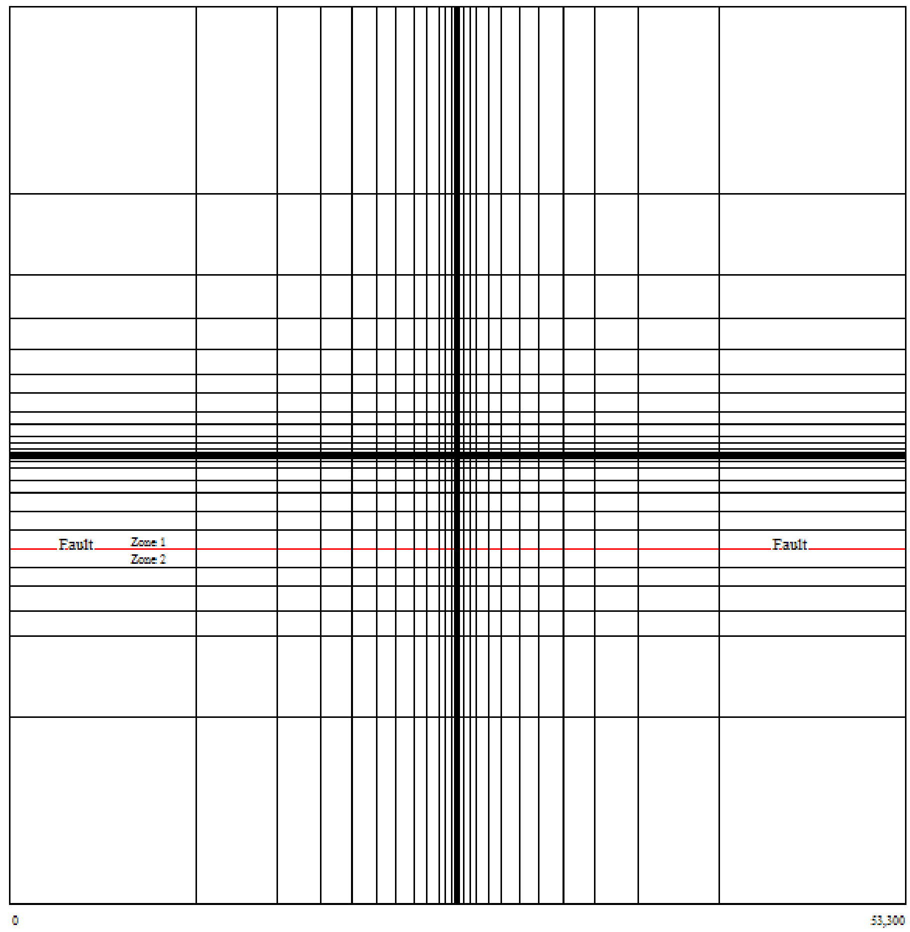
VII.B.2 Layer Thickness

To determine appropriate thickness values of the injection reservoir geophysical logs were used. A total net layer zone thickness of 145 feet was identified for injection into the Lower Cockfield at the well location. (See Table VII-1) For the area past the fault identified in the geology review, a net thickness of 401 feet for the Middle Cockfield Sand was used for the model parameters.

VII.B.3 Structure

The geologic structure of the Cockfield was gathered from geologic structure maps pulled from the original WDW-315 application submitted in 1994 which was verified by ALL's geologist and based upon tops of the Cockfield identified in surrounding wells (see **Figure V.B.1.7**). This supplied structure map was overlain with a data grid and used to create an injection reservoir structure for import into the model. **Figure VII-1** presents the model grid developed for the WDW-315 model.

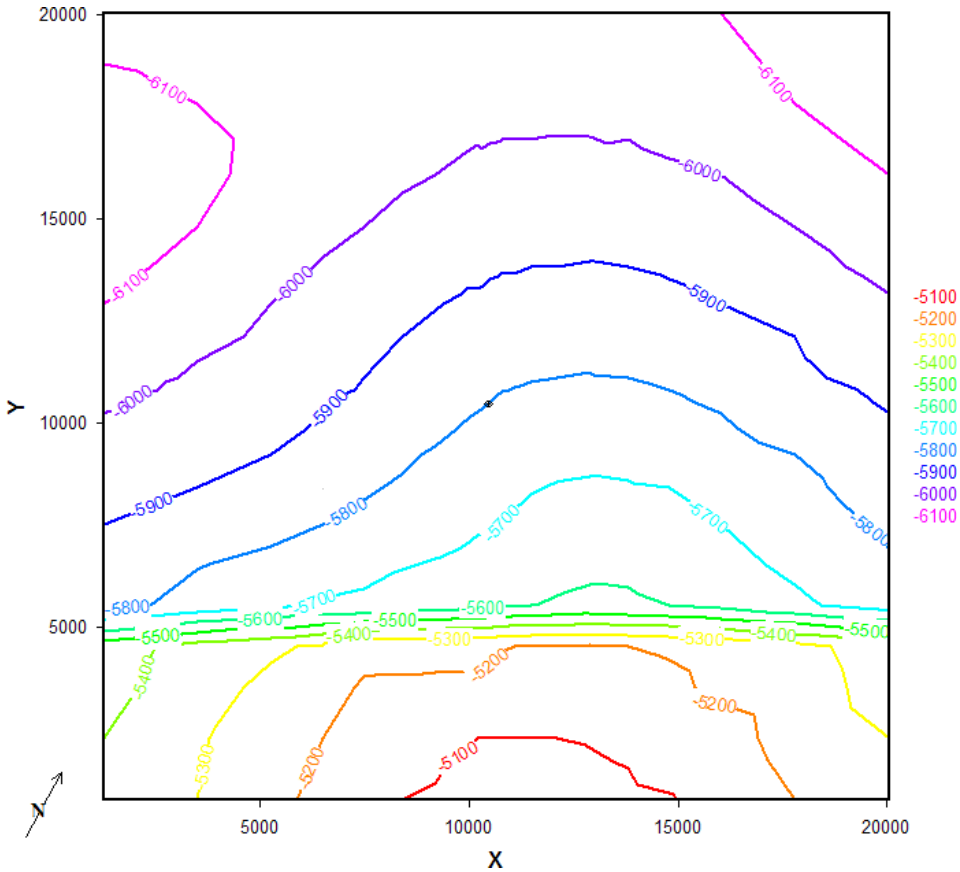
FIGURE VII-1
Model Grid
Diagram of model grid with Fault line presented. Approximate 10x10 mile model area with closed boundary. Detailed grid-blocks around center masked due to scale of image. Zones presented are used in modeling efforts.



In the portion of the model grid presented above where the wellbore resides the modeled injection reservoir contains only the Lower Cockfield formation. On the other side of the fault presented in Figure VII-1 both the Middle and Lower Cockfield are modeled.

Figure VII-2 presents a structure map generated without structural edits from the model input data. This input data can be compared to the structural data presented in Figure V.B.1.7.

FIGURE VII-2
Structural Map of Area Surrounding Well
Developed structural map of the model area from contouring software and based on model input values.



VII.B.4 Permeability and Skin

Permeability is the capacity of porous media to transmit fluids. An averaged homogenous permeability of 80.9 md was determined from a well testing event performed after the initial well completion in December 1999. Based on review of the perforation record, log analysis, and core analysis performed on the well it is believed that the derived permeability from the well test analysis is not representative of the reservoir conditions. Estimates of reservoir permeability has been as high as 1,400 md based on literature review. Core analysis conducted on the Lower Cockfield indicated a permeability range of 550 md to 850 md for the portion of the formation planned for perforating after permit approval. A reservoir permeability of 500 md was used in the modeling effort based on the review of logs and core analysis. This value is believed to be more representative of the injection zone and still considered to be a conservative number.

For modeling a value of zero (0, no increase or decrease in effective flow conditions) was used for the model's skin factor as skin is a variable function over time and is dependent upon the condition of the wellbore.

VII.B.5 Porosity

Porosity is the ratio of void space in a given volume of rock to the total bulk volume of rock expressed as a percentage. The more porous a rock the more fluid can be stored in a given rock volume. The values presented in Table VII-2 were used in the model for porosity values relative to the Lower Cockfield and combined Middle/Lower Cockfield zones. These values were derived from density, neutron, and sonic logging of the well and assuming a sand lithology.

TABLE VII-2
Modeled Porosity

Formation	Porosity
Zone 1*: Lower Cockfield	24.0 %
Zone 2*: Middle/Lower Cockfield	27.6 %

* Zone 1 at wellbore and Zone 2 Past Fault (see Figure VII-1).

VII.B.6 Saturation and Relative Permeability

From evaluation of the open-hole logs on the test well, water saturation in Cockfield formation is considered to be at 100%. Therefore, water relative permeability is 1.0.

VII.B.7 Temperature

A static reservoir temperature was measured in the wellbore at 6,200 ft of 185.85°F. This provides a gradient of 3.0°F per 100 feet of depth. This gradient was used to estimate temperature in the injection reservoir.

VII.B.8 Compressibility

Compressibility is the change in volume per unit increase in pressure. The rock compressibility was estimated to be 3.7 x 10^{-6} psi^{-1} and the water compressibility was estimated at 5.88 x 10^{-6} psi^{-1} from standard correlations (Earlouger, 1977).

VII.B.9 Injection Reservoir Fluid

The formation fluids in the Lower Cockfield are typical of producing formations in the Gulf Coast. The fluid is a brine with a high total dissolved solids (TDS) content (105,000 part per million (ppm)). The formation fluid was sampled after the original well completion in December 1999 and a copy of the analytical results is contained in Volume X – Well Completion Report.

VII.C Reservoir Model Parameters

VII.C.1 Model Construction

The reservoir model constructed for pressure predictions is based on placing the well in an approximate 10-mile square model. The model is configured for closed outer boundaries. This provides a very conservative approach (higher build-up pressures) to the model pressure buildup as compared to using an infinite acting outer boundary condition. The area was divided into a 25 block by 27 block by 1 layer grid block model of the underground injection area. The grid was proportioned in such a manner to have greater detail around the wellbore. The injection well was modeled in a 100-foot by 100-foot grid block with the grid block sizes increasing away from the wellbore to simulate the injection zone reservoir. Figure VII-1 represents the model grid used to represent the reservoir. The apparent thicker lines crossing at the center represent the smaller grid blocks radiating from the wellbore.

VII.C.2 Model Input Parameters

Input parameters for the reservoir model were generated from geologic data, drilling logs, wireline logging, standard correlations, structural maps, and analysis of injection/fall off testing. A single layer was chosen to represent the reservoir in the numerical model. The layer is divided into two zones to account for a fault located south of the injection well which displaces a portion of the formation. Zone 1 is the Lower Cockfield formation and Zone 2 is the combined Lower and Middle Cockfield formations. The following table provides a summary of the reservoir characteristics obtained from the above mentioned sources and the values used in the modeling efforts for the represented two zones.

TABLE VII-3
Model Input Parameters

Zone	Layer TOP Depth (ft, bls)*	Net Layer Thickness (ft)	Porosity %**	Permeability (md)	md-ft	Temperature (F)
1	6045	145	24	500	72,500	181
2	5546	401	27.6	500	200,500	166

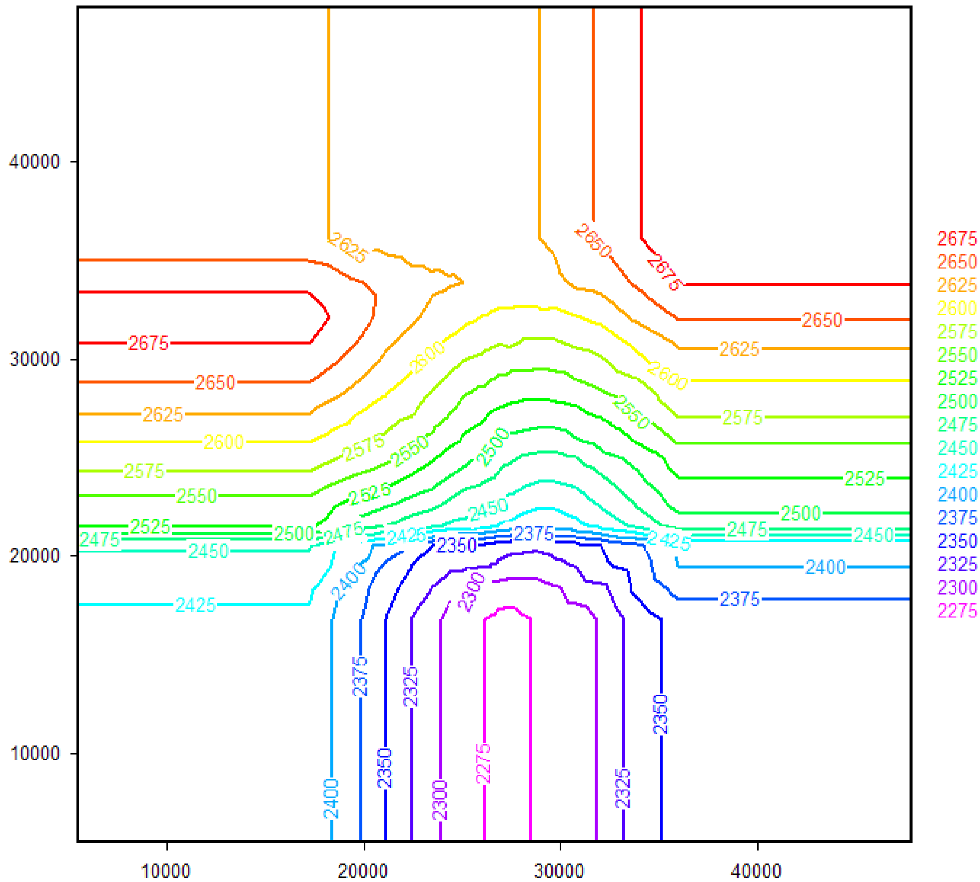
* At Wellbore location.
** For initial modeling effective considered same as total.

VII.D Reservoir Pressure Analysis

VII.D.1 Initial Static Reservoir Pressure

Data from the well testing event (12/17/1999) performed on the injection well was used for the initial static reservoir pressure, since there was no prior injection. At a depth of 6,200 feet a pressure of 2502.28 psi was measured. Using these numbers yields a pressure gradient in the wellbore of .404 psi/ft.

FIGURE VII-3
Pressure at Initialization
Pressure contours at the initialization of the model.



VII.D.2 Estimation of Fracture Pressure

Fracture pressure is defined as the surface pressure that if applied would fracture the objective formation. The maximum surface pressure for a Class I injection well must not be higher than the fracture pressure of the injection zone. The fracture gradient for the injection interval can be estimated by Eaton's Method (Moore, 1974), as follows:

$$FG = \frac{(P_{ob} - P_r)e}{(1 - e)} + P_r$$

Where:

FG:	Fracture Gradient
P_{ob}:	Overburden Gradient (Figure 11-11 in Moore, 1979)
P_r:	Reservoir Pressure Gradient (original)
e:	Poisson’s Ratio (Figure 11-12 in Moore, 1979)

$$FG = \frac{(1.0 - 0.406)0.4}{(1 - 0.4)} + 0.406$$

FG = 0.802 psi/ft

For the Cockfield Sand injection interval a fracture gradient of 0.802 psi/ft was calculated and using the calculated fracture gradient, the fracture pressure P_{frac} for the top depth of Layer-1 of injection interval is estimated as:

$P_{frac} = FG$ * Depth to top of uppermost injection interval

P_{frac} = 0.802 * 6,045 feet

P_{frac} = 4,848 psi

The surface pressure required to reach the bottom hole fracture pressure is determined by subtracting the hydrostatic head of the wastewater from the bottom hole fracture pressure (discounting any friction losses).

P_{hydro} = ρ x 0.052 x Depth

P_{hydro} = 10.8 ppg x 0.052 x 6,045 ft = 3,395 psi

Surface Fracture Pressure = P_{frac} - P_{hydro}

Surface Fracture Pressure = 4,848 psi – 3,395 psi

Surface Fracture Pressure = 1,453 psi

TABLE VII-4
Lower Cockfield Fracture Pressure

Formation	Fracture Gradient (psi/ft)	Formation Fracture Pressure at 6,045 feet (psi)	Formation Fracture Pressure at Surface (psi)
Lower Cockfield	0.802	4,848	1,453

VII.D.3 Maximum Allowable Surface Injection Pressure

The maximum allowable surface injection pressure (MASIP) is the maximum surface pressure that an injection well is allowed to inject fluid into the injection well. This pressure is based on the pressure required to inject or propagate fracture within the injection fracture. According to TCEQ (reference?), the MASIP is not to exceed fracture pressure minus initial reservoir pressure minus change in reservoir pressure minus 100. Losses due to friction pressure are not included in the calculation.

MASIP = P_{frac} - (P_{hydro} + P_{form}) – 100.

P_{frac} = 4,848 psi (See Above)

P_{hydro} = 3,395 psi (pressure at top of Lower Cockfield - 6,045 ft.)

P_{form} = 0 psi (reservoir at initial conditions)

MASIP = 4,848 - (3,395 + 0) - 100

MASIP = 1,453 psi

TABLE VII-5
Requested Maximum Allowable Injection Pressure

Injection Interval	Requested Surface Injection Pressure
Lower Cockfield	1,250 psi

VII.E Reservoir Modeling

VII.E.1 Reservoir Model

BOAST98 was used to evaluate reservoir performance. The original BOAST was released in 1982 by the U.S. Department of Energy. BOAST II (Franchi, 1987) was released in 1987 (see Appendix 2), and it was designed to overcome the limitations of the original BOAST. Features were added which would improve the versatility of the program. In 1995, BOAST II was modified to accurately simulate the conditions encountered in steeply dipping high permeability reservoirs. The modified model, named BOAST 3-PC, is used for performing evaluation and design work in modern petroleum reservoir engineering. Many features were added to improve the versatility of the model. BOAST98 (Heemstra, 1998) was released in 1998. The new model improved the user interface with a Windows interface.

The reservoir evaluation is based on several variables: finite-difference, implicit pressure, and explicit saturation, with options for both direct and iterative methods of solution. The reservoir is described by three-dimensional grid blocks and by three fluid phases. Other options include steeply dipping structures, multiple rock and PVT regions, bubble point tracking, automatic time step control, material balance checking for solution stability, multiple wells per grid block, and rate or pressure constraints on well performance.

VII.E.2 Prediction of Reservoir Pressure Increase

VII.E.2.a Modeled Injection Rate

For this permit application, modeling of injection at the facility considered three output time frames: 1-year injection; 10-year injection; and 30-year injection (anticipated facility life). Projected injection is modeled with one well centered in the model grid. A constant injection rate of 12,000 barrels per day for the well is modeled for the entire 30 year anticipated facility life. This yields an injection rate of 350 gpm, 24 hours a day, 7 days a week which is considered conservative (i.e., actual injection volumes are expected to be much less than modeled amount) based on the anticipated operation of the well.

VII.E.2.b Model Results

Whenever effluent is injected into a subsurface geological formation, the pressure within the reservoir used for injection will increase. This pressure increase will be greatest at the well and will decrease with distance away from the site.

The simulation model run for the proposed Lower Cockfield injection interval was made to predict average lateral pressure distributions for 1 year, 10 years, and 30 years at the proposed maximum injection rate. Table 7 provides a summary of the results of the BOAST98 modeling of the injection pressure buildup at the injection well.

TABLE VII-6
Summary of Modeled Reservoir Maximum Injection Pressure at the Wellbore

Time Step	Initial	1 year	10 years	30 years
Reservoir Pressure at Wellbore (psi)	2512	2715	2828	3071
Pressure Increase at Wellbore (psi)	0	203	316	559

Figure VII-4 provides a summary graph of the change in reservoir pressure at the injection well over the 30 years of injection simulated by the reservoir model. Reservoir pressure distribution contour plots for year 1 and year 30 are shown in Figures VII-5 & VII-6. The Time Step summary for each time period and the Total Run Summary of simulation are listed in the attached Modeling Reports in **Appendix 1**.

FIGURE VII-4
Pressure Change in Injection Layers at Wellbore
Plot of pressure change over time at the wellbore.

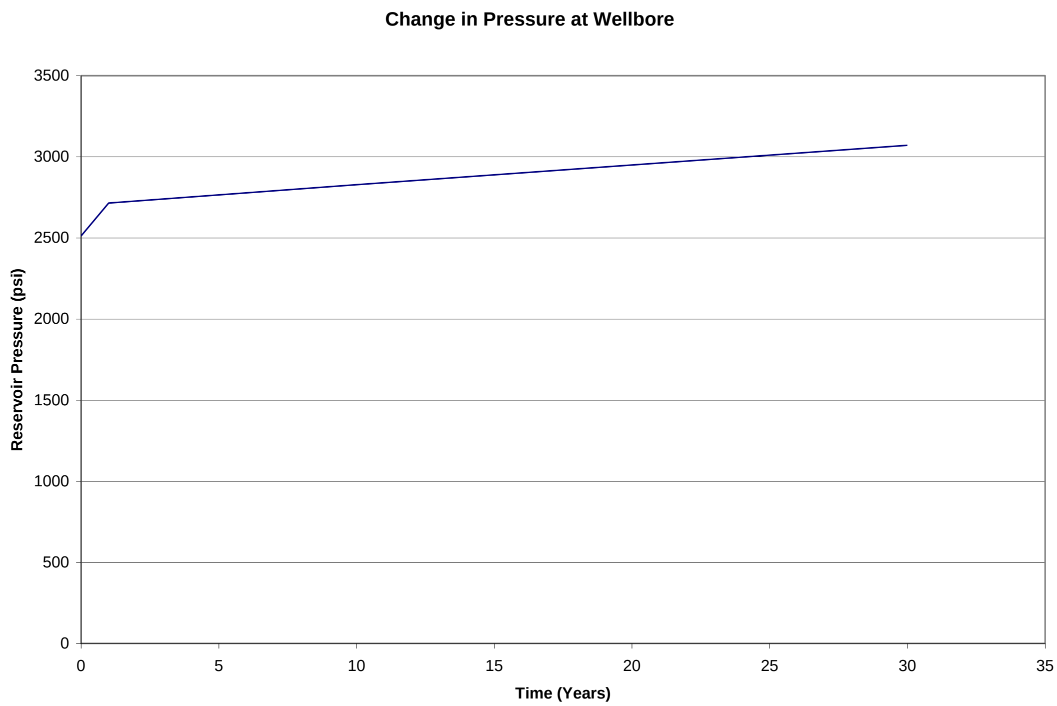


FIGURE VII-5
Pressure Year 1
Pressure contours after 1 year of modeled injection.

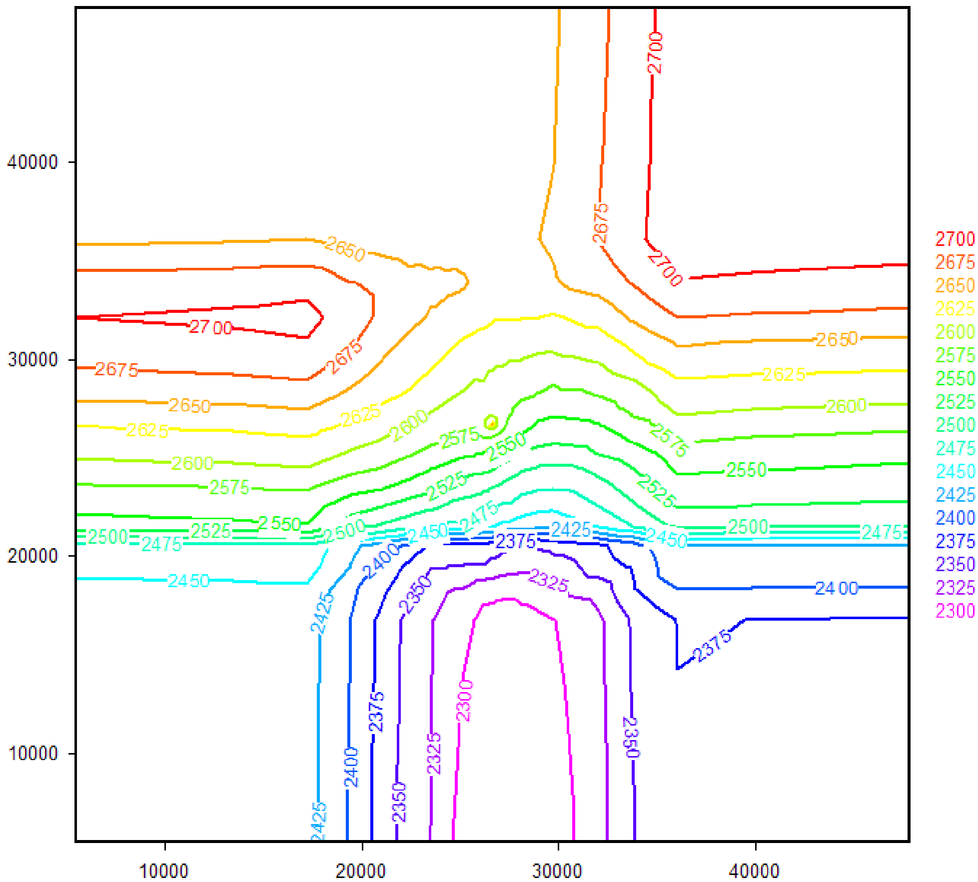
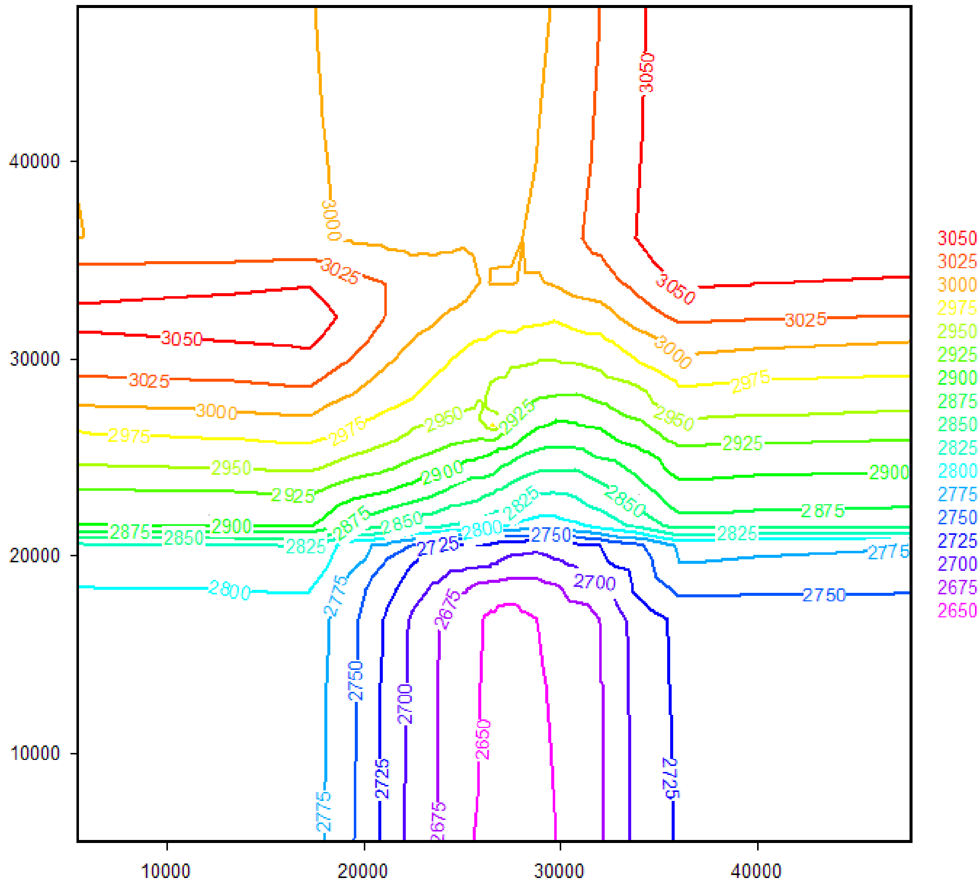


FIGURE VII-6
Pressure Year 30
Pressure contours after 30 years of modeled injection.



VII.E.3 Extent of the Wastewater Plume

The results from the model were used to calculate an estimated lateral extent of the injected effluent into the Lower Cockfield Sand through a volumetric analysis.

The results from the BOAST98 model showing that the injection volume of 12,000 bbls/day was capable to be injected and not overpressure the reservoir were used for the radial extent calculations. Using the fact that 12,000 bbls/day is capable of being injected, a volumetric analysis was then performed for radial extent. The injected volumes and parameters used in the radial extent calculations are presented below (the same reservoir parameters used in the model were used in the radial extent determination).

Constants & Reservoir Parameters:

Pi (π) = 3.1416
Cubic Feet per Barrel (C) = 5.6146 ft3/bbl
Reservoir thickness (H) = 145 ft
Formation Porosity (ϕ) = 24%

Irreducible Water Saturation (Sirr) = 12%
Injection Rate (Q) = 12,000 bbl/day
Days Injected (D, 30 years) = 10,957.5 days, (D, 10 years) = 3,652.5

Assumptions:

Assumed a Radial Flood Pattern
Assumed Homogeneous Reservoir
Volumetric calculation using following equation for Reservoir Volume (RV, Injected Volume):

$$RV = \pi \times r^2 \times (1 - S_{irr}) \times \phi \times H$$

and

$$r = \sqrt{\frac{RV}{\pi \times (1 - S_{irr}) \times \phi \times H}}$$

Assume Radial Flood:

A = pi * r2

Volume = A * H

Volume Injected = q * days

Volume Injected = 246,087,918 ft3 – 10 years

Volume Injected = 738,263,754 ft3 – 30 years

Volume Reservoir = pi * r2 (1 - .12) * .24 * H

r (10 years) = 1,599.332 ft.

r (30 years) = 2,770.125 ft.

½ mile = 2,640 ft.

Therefore: Plume radius after 30 years is just over ½ mile from wellbore.

The following table summarizes the expected radius of the injected effluent at different time steps:

TABLE VII-7
Estimated Radial Extent of Wastewater Plume

Time Step	10 years	30 years
Radius (feet)	1,599	2,770

*Irreducible water saturation of 12% assumed for modeling.

The waste plume is only expected to reach a maximum of 2,770 feet from the wellbore after 30 years of injection. Therefore, the Area of Review radius in this application is set at the minimum distance of 2.5 miles for the 30 years of injection of the predicted facility life.

VII.F Calculation of the Cone of Influence

VII.F.1 Methodology

The methodology used in this permit application for calculating the cone of influence for the proposed injection well site is based on the assumption that the pressure increase in the injection zone and reservoirs must be greater than the static fluid column in an artificial penetration before upward migration can commence. The assumption is that in the absence of naturally occurring, vertically transmissive conduits (faults and fractures) between the injection interval and any USDW, the only potential pathway between the injection zone and any USDW is through an artificial penetration (active or inactive oil, gas, and injection well[s]). To initiate upward flow, the pressure increase in the injection zone must be greater than the pressure necessary to displace the material residing within the borehole (defined as the allowable buildup pressure). Therefore, the cone of influence is the area within which the pressures in the injection zone may cause the upward movement of injection or formation fluid into a USDW.

This pressure increase was estimated by studying the reservoir mechanics and conducting reservoir modeling. The allowable pressure buildup (static column pressure plus minimum gel strength) at the top of the injection zone (using well-specific information such as mud weight, borehole diameter, formation depth) was calculated for comparison to the reservoir modeling pressure build up results. Conservative assumptions were made in the calculations to assess the potential cone of influence base on the maximum requested injection volumes. These assumptions are summarized below:

- For purposes of calculating the pressure due to gel strength, a 20-pound per 100-square-foot (sq. ft.) gel strength was used. This is conservative, as studies indicate that with time, the gel strength of mud may be more than an order of magnitude higher (Pierce, 1989).
- In order to be extremely conservative in calculating the static column pressure, a fallback of 50 feet in the mud column was assumed.

Fluid dynamics determines the effect of injection on adjacent well bores. A static fluid column exerts pressure on the formation; therefore, the pressures acting on the column (pressure due to injection plus original formation pressure) must be greater than the static fluid column pressure before upward fluid movement will start. In other words, for upward fluid movement to begin, the original formation pressure (P_f) plus the pressure due to injection (P_i) must be greater than the static fluid column pressure in the well bores, as shown in the equation below:

$$P_f + P_i > P_s$$

where:

P_f = original formation pressure (pounds per square inch gauge [psig])

P_i = formation pressure increase due to injection (pounds per square inch [psi])

P_s = static fluid column pressure (psig)

In other words, pressure increase due to injection must be greater than static fluid column pressure minus original formation pressure, as seen here:

$$P_i > P_s - P_f$$

Static fluid column pressure is calculated using the following equation:

$$P_s = 0.052 \times h \times \rho$$

where:

h = depth to the injection reservoir from the 50-foot fallback (ft.)

ρ = fluid weight (pounds per gallon [lb./gal.])

0.052 = conversion factor (gal./ft.-in.^{2})

In an artificial penetration filled with drilling mud, the gel strength of the mud must also be considered. In this case, for upward fluid movement to begin the original formation pressure (P_f) plus the pressure due to injection (P_i) must be greater than the static fluid column pressure plus the gel strength of the mud. This relationship is based on this simple balance of forces (Davis, 1986):

$$P_f + P_i > P_s + P_g$$

where:

P_f = original formation pressure (psig)

P_i = formation pressure increase due to injection (psi)

P_s = static fluid column pressure (psig)

P_g = gel strength pressure (psi)

Therefore, the pressure increase due to injection must be greater than static fluid column pressure plus the pressure due to gel strength minus original formation pressure, demonstrated as follows:

$$P_i > P_s + P_g - P_f$$

The pressure due to gel strength (G) in an open borehole can be calculated from the following equation:

$$P_g = \frac{0.00333 \times G \times h}{d}$$

where:

P_g = pressure due to gel strength (psi)

G = gel strength (pounds per 100 square feet [lb./100 ft.^{2}])

h = depth to the injection reservoir from the 50 foot fallback (ft.)

d = borehole diameter (in.)

0.00333 = conversion factor

VII.F.2 Cone of Influence Calculations

The initial step in calculating the allowable buildup pressure (cone of influence) for the Lower Cockfield injection zone at the injection well site involved determining the maximum pressure buildup gradient. The following data was assumed or derived from the injection well as information to be used in the cone of influence calculations.

TABLE VII-8
Cone of Influence Data

Property*	**Value**
Mud Weight	9.0 ppg
Depth Top Injection Reservoir (Layer 1)	6,045 ft
Well Diameter	7.0 in
Gel Strength	20 lb/100 sq ft
Initial Injection Reservoir Pressure (Top Layer 1)	2,442 psi

* Values used are based on injection well location.

A review of the state forms and well logs indicates that the minimum mud weight used by operators in the area is 9.0 ppg. The maximum allowed pressure buildup gradient was derived by first calculating the mud column gradient (from the minimum mud weight and subtracting from it the original formation pressure gradient of the injection interval.

This is demonstrated for the Lower Cockfield injection reservoir by the following:

0.052 x 9.0 ppg = 0.468 psi/ft. (mud column gradient)

2,442 psi/6,045 ft = 0.404 psi/ft. (current formation pressure gradient of Lower Cockfield injection zone)

0.468 - 0.404 = 0.064 psi/ft. (maximum allowed pressure buildup gradient, based on 9.0 ppg mud)

Thus, 0.064 psi/ft. is the maximum pressure buildup gradient based on mud weight allowed in the Lower Cockfield injection interval prior to possible fluid movement. This translates to a pressure increase of 387 psi (0.064 psi/ft. x 6,045 ft.).

Additionally, the pressure buildup needs to include the pressure required to overcome the gel strength of the mud column. A minimum gel strength pressure was determined using a conservative value of 20 lb./100 sq. ft. for the gel strength, along with an 7-inch borehole (. As an additional measure of conservatism, a 50-foot fallback of the mud column from the surface was utilized in each of the following calculations.

$$P_g = \frac{0.00333 \text{ x } G \text{ x } h}{d_b - d_c} = 0.00333 \text{ x } 20 \text{ x } (6{,}045 - 50) / (7) = 57 \text{ psi}$$

At top of the Lower Cockfield Sand, static fluid column pressure from mud is as follows:

$$P_s = 0.468 \text{ x } (6{,}045 - 50) = 2{,}806 \text{ psi}$$

The maximum allowable pressure increase is shown below:

$$P_i = P_s + P_g - P_f = 2{,}806 + 57 - 2{,}442 = 421 \text{ psi}$$

If you compare the maximum allowable pressure increase calculated above (421 psi) to the maximum buildup pressure based on mud weight gradient plus the gel strength (387 psi + 57 psi = 444 psi); the mud weight based pressure is higher. Therefore, TexCom has used the lower of the two calculated pressures in determining the Cone of Influence.

Table VII-9 summarizes these results for the Lower Cockfield Sand injection interval at the proposed injection well site.

Table VII-9
Maximum Pressure Increases

	Area of Review		
Injection Interval	**Maximum Model Pressure Increase at Wellbore End of 30 Years**	**Maximum Model Pressure Increase in Injection Zone at 150 feet End of 30 Years**	**Maximum Allowable Pressure Increase Cone of Influence**
Lower Cockfield	559 psi	456 psi	421 psi

It is important to note that the current calculations of the AOR are very conservative and contains significant additional safety factors, including the actual weight of the mud in the borehole, the actual gel strength of the drilling mud, and the borehole closure. They also assume minimum rugosity in the borehole and no cement plugs between the injection zone and the USDW. There are three wells locate within 150 feet of the proposed wells. Each of the wells was completed in the Upper Cockfield production zone at approximately 5,200 feet. None of the wells penetrate into the Middle or Lower Cockfield formation.

Since the injection zone includes the entire Cockfield formation due to the potential for communication between the three layers of the formation, these wells technically penetrate the injection zone. In reality, the wells are completed more than 800 feet above the Lower Cockfield injection zone and the additional pressure required for injection to force fluids through the formation to the boreholes is significant. The vertical pressure required to lift fluid through the shale sand sequences would be higher than the pressure available in the injection zone. In addition, the permeability of the Middle and Upper portions of the Cockfield formation is higher than the Lower Cockfield and would act as a pressure sink which would lower the pressure buildup in the well area.

Therefore, the Cone of Influence for the injection well would be zero feet based on the small amount of pressure buildup in the Lower Cockfield and the fact that the wells located within the Area of

Review are completed in the higher permeability Upper Cockfield sand which is 800+ feet above the Lower Cockfield injection zone.

Table VII-10
Cone of Influence Summary

Maximum Allowable Pressure Increase	421 psi
Cone of Influence	0 feet

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